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Justification for Oil Well Stimulation

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ABSTRACT

In the process of drilling wells or carrying out treatment operations on the wells, the characteristics of the reservoir around the vicinity of the well changes due to the invasion of fluid when compared to zones further away in the reservoir. During the stimulation exercise, there is an increased tendency of emulsion formation with the acid concentration and in reality, most crude oils contain natural chemicals which frequently act to stabilize emulsions formed with acid or with spent acid and this severely hinders production due to the high viscosities inherent with emulsions and also, some crude oils chemically react with hydrochloric acid to form solid or semi-solid particles called asphaltene sludge. This can restrict or completely plug the flow channels in the producing formation thereby reducing the effectiveness of the acid treatment and also due to its insoluble in most treating solutions. In this study, pressure transient analysis was performed on well J8 and K35 of an oil field in the Niger Delta to determine the extent of formation damage around the wellbore, a pre and post evaluation on the stimulation job to ascertain the efficacy of the stimulation job is also presented. Result show that it is very important to determine the type of skin on each well, this well help in knowing the type of solution to the problem in order to increase the well's productivity because a well whose skin is due to completion, partial penetration or slanting of well does not require stimulation and if the field's operators go ahead to stimulate, they will only end up in wasting time and money without achieving any result because these skin cannot be removed by stimulation.

Keywords - *formation damage, stimulation, fluid invasion, wellbore, drilling, emulsion, sludge, skin, productivity, permeability and stimulation candidate selection.*

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I. INTRODUCTION

When an oil or gas reservoir is penetrated by a well, its content flows naturally to the surface production facilities with the aid of the primary reservoir drive mechanism via production conduit. This means that the natural tendencies for oil and gas wells are to maintain reservoir pressure and production rate to be high at initial condition and a gradual decline in reservoir pressure and production rate as the wells drilled into the reservoir as the wells are producing. In reality, the drilling and completion of oil and gas wells for production are always not successful without damage to the formation as a result of drilling mud invading the hydrocarbon pay zones, cement and completion fluid filtrate invasion, solid invasion, fines migration, swelling clays, paraffin deposition, scale precipitation and the effect of stimulation treatments, to mention a few. Hence, it is evident that formation damage problems are caused by the nature of our activities during the process of interactions with our wells causing as impairment of reservoir permeability around the well bore, leading to low or no well production.

To optimize production amidst some of the causes of formation damage mention above, we need to stimulate some of the wells drilled into the reservoir when the flow of oil becomes too small. Furthermore, we need to understand that it is not all wells diagnosed with positive skin are recommended for stimulation. Here stimulation is defined as a term used to describe different operation carried out in a well to get optimum productivity. This operation is focused on a new and old wells; also it can be designed for remedial purposed or for enhanced production.

Due to foreign particle invasion and plugging, formation clay dispersion and migration, chemically incompatible fluids, oil wetting of reservoir rock, emulsion and water blocking and fluid invasion. It is therefore pertinent for a successful stimulation operation to consider some of the factors when designing an acidizing job. During the treatment exercise, water can be dispersed as fine droplets in the bulk of oil forming an emulsion which requires the use of an emulsifier, formation of asphaltene sludge which an anti-sludge agent to break the mixture of crude oil and acid, the dispersion and migration of clay which have the tendency to block the flow channels of the acid and if iron agents are not used, formation containing naturally occurring iron may form precipitates. Therefore, it is the objective of this study to evaluate the performance of oil well after stimulation operation to justify its successes.

II. SKIN EFFECT

In the process of drilling a well or carrying out treatment operations on the well, the characteristics of the reservoir around the vicinity of the well changes due to the invasion of fluid when compared to zones further away in the reservoir. This leads to the concept termed skin effect refer to as the level of formation damage around the wellbore but we should be aware that the damage on the formation is not limited to initial production operations. In the reservoir, skin is presented mathematically as a region of decreased or increased permeability around the wellbore. The factor of skin can either be negative or positive. A positive skin factor denotes damaged well or impediment to well productivity which implies an increase in pressure drop. On the other hand, a negative skin means a stimulated well or shows productivity enhancement and it implies a decrease in pressure drop at the interface between the reservoir and the wellbore (Agarwal et al., 1970, Ramey, 1970). Productive geothermal wells usually display a negative skin factor. According to Horne (1995), the skin effect can be described in terms of an effective wellbore radius which is the radius that the well appears to have due to the reduction or increase in flow caused by the skin effect. The equations below represent ways of determining skin factor, s.

Build up test

$$s = 1.1513\left[\left(\frac{P_{1hr} - P_{ws(tp)}}{m}\right) - \log\frac{\mathrm{k}}{\emptyset\mu c_t r_w{}^2} + 3.2\right] \quad (1)$$

Drawdown test

$$s = 1.1513\left[\left(\frac{P_i - P_{ihr)}}{m}\right) - \log\frac{\mathrm{k}}{\emptyset\mu c_t r_w{}^2} + 3.2\right] \quad (2)$$

Determination of skin due to damage

$$S_d = \left(\frac{k}{k_I} - 1\right) ln\frac{r_i}{r_w} \quad (3)$$

$r_i = r_s + r_w$

If $k > k_i$, $S_d > 0$ (damaged) and if $K < k_i$, $S_d < 0$ (stimulated)

Pseudo skin due to penetration (full penetration of the entire interval)

$$S_T = S_c + S_d + S_p + S_{sw} \quad (4)$$

Pseudo skin due to penetration (partial penetration for shallow damage skin)

$$S_T = S_c + \frac{h_T}{h_p}\left[S_d + S_p + S_{sw} + S_i\right] \quad (5)$$

Pseudo skin due to penetration (partial penetration for deep damage skin)

$$S_T = S_c + S_d + \frac{h_T}{h_p}\left(S_p + S_{sw} + S_i\right) \quad (6)$$

Pseudo skin due to Slanting of Well, $\boldsymbol{S_{sw}}$

The pseudo skin due to slanting of well depends on the angle of slant, α, and ratio of total thickness to wellbore radius,$\frac{h_T}{r_w}$ It can be approximated using the equation published by Cinco, Miller and Ramey. The equation is

$$S_{sw} = -\left(\frac{\alpha}{41}\right)^{2.06} - \left(\frac{\alpha}{56}\right)^{1.865} \log\left(\frac{h_T}{100r_w}\right) \quad (7)$$

And it is valid for $0 < \alpha > 75^0$ and $\frac{h_T}{r_w} > 40$ (i.e. about $h_T > 12ft$

Pseudo skin due to Partial Completion (Mechanical Skin), $\boldsymbol{S_c}$

This depends on the ratio of completed interval hp to formation thickness, h_T (most important parameter), location of completion relative to total thickness and ratio of vertical to horizontal permeability.

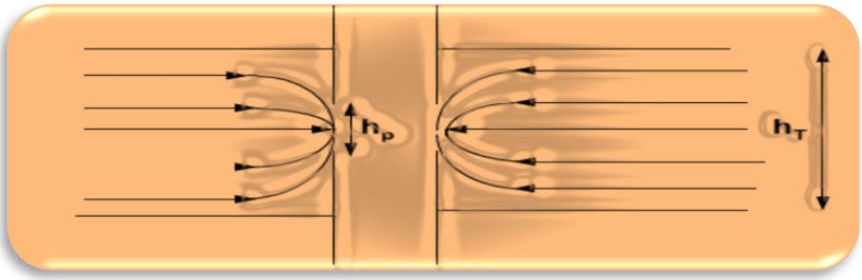


Figure 1: configuration of partial completion

$$S_c = \left(\frac{h_T}{h_p} - 1\right)\left\{\ln\left(\frac{h_T}{r_w}\sqrt{\frac{k_H}{k_v}}\right) - 2\right\} \quad (8)$$

Where,
S_d = skin due to damage, S_p = skin due to perforation, S_c = skin due to completion, S_{sw} = skin due to slanting of well
S_T = total skin, h_T = formation thickness (ft), h_P = completion interval (ft), K = permeability (mD), K_i = damaged permeability (mD), r_i = damaged radius (ft), r_w = wellbore radius (ft), r_s = depth of damage (ft), K_v and K_h are vertical and horizontal permeability.

III. STIMULATION CANDIDATE WELL SELECTION

Okotie et al (2014) developed a model for stimulation candidate well selection base on skin due to damage, production increase, economics, payback period and the R-factor. Seven wells were used and the results obtained after the candidate well selection for stimulation job will help the company and other companies to prioritize their wells based on the model they choose. For instance, in a field; there are several wells drilled into the reservoir and to select which of these wells to stimulate first becomes a challenge. Weingarten and Perkins (1992) stated that critical drawdown is used to predict expected production and is important in evaluating the economic potential of the treatment. This implies that when screening wells for stimulation job, potential production increase and incremental economics should be adopted. Thus, wells with the greatest potential should be selected as candidates. This process should include determination of the maximum allowable drawdown pressure before formation or sand production occurs. Gas Research Institute (GRI) believes that candidate-well selection phase is where the greatest industry benefit resides. Moreover, many stimulations fail because of poor-candidate selection. GRI also argue that good producers often are the best candidate, even though that seems counterintuitive (Ely *et al.*, 2000).

Martin, (2010) described the process of selecting candidate-wells as a challenging task for hydraulic fracturing treatment for the increase of well productivity. Martin and Raylance (2010); Martin and Economides (2007); Mohaghegh (2001) have a common view about candidate-well selection; there is not a straightforward process and up to now, there has not been a well-defined and unified approach to address this process. However, Moore and Ramakrishnan (2006) believed that it is possible to formulate a framework for proceeding with the candidate-well selection for a certain field. Howard and Fast (1970) noted that the fracture selected for use in a treatment should possess the following properties: Low fluid loss, ability to carry and suspend the proppant, low friction loss, easy to recover from the formation, compatible with formation fluids and non-damaging and reasonable cost. It is now possible to achieve most or all of these objectives by properly selecting the chemical composition of a fracture fluid. There are very few situations for which fracturing is technically impossible because of fluid limitations. This is, of course, not to say that all cases which are technically possible will also be economically attractive.

In the acidizing concepts and design, BJ services at the acidizing seminar, BP Indonesia stated that wells with zonal damage are good candidates for well stimulation treatments which can result to major increases in productivity. The well and the treatment, however, should be selected with care, and reservoir conditions should be adequate to assure economic pay-out. Misapplied stimulation treatments are costly and ineffective, often creating more problems than they solve. Selecting the correct treatment is often not a simple matter. With an engineering approach to any well problem however, the chance of success is generally increased. The following information should be considered in the selection of a well treatment:

- Type of formation and mineral composition of the formation.
- Type and amount of damage.
- Contact time available for chemical treatment.
- Physical limitations of well equipment.
- Bottom hole pressure and temperature.
- Possible contaminants such as water, mud, cement filtrate and bacteria.
- Treating fluid compatibility with contaminants present and reservoir fluids.
- Formation properties such as acid solubility, permeability and porosity.

IV. WHAT ARE THE TECHNIQUES AVAILABLE TO REMOVE THE DAMAGE FROM THE FORMATION?

Basically, there are two methods of stimulating a well to remove the damage due to skin; these are matrix acidization and hydraulic fracturing. We have to note at this point that among the types of skin, it is only the skin due to damage that can be stimulated. Matrix acidization involves the placement of acid within the wellbore at pressures and rates made-up to attack the restriction to flow without damaging the reservoir. In this treatment, the acid is injected into the pores and flow channels of carbonate rocks at a bottom-hole pressure considerably less than the fracturing pressure the purpose being to increase uniformly. On the other hand, hydraulic fracturing implies acid fracturing, involves the injection of a variety of fluids and other materials into the well at rates that actually cause the cracking or fracturing of the reservoir formation. These techniques usually cause a highly conductive flow path between the reservoir and the wellbore.

V. EVALUATION OF STIMULATION JOB

The formation of emulsion is one of the challenges facing the oil and gas industry today. This is normally encountered when water is dispersed as fine droplets in the bulk of oil. Thus, during the stimulation exercise, there is an increased tendency of emulsion formation with the acid concentration and in reality, most crude oils contain natural chemicals which frequently act to stabilize emulsions formed with acid or with spent acid and this severely hinders production due to the high viscosities inherent with emulsions. After the stimulation job, an additional expense is incur in trying to dispose the aqueous phase of the emulsion. It is therefore imperative to perform emulsion tests using crude oil samples from the well to be stimulated or treated and the proposed acid treating solutions.

Sludges form when asphaltenes are precipitated out of the crude oil. The hydrocarbon formation contain asphaltic material which exists as a colloidal dispersion of minute asphaltene particles permeated by adsorbed maltenes. During stimulation treatments some crude oils chemically react with hydrochloric acid to form solid or semi-solid particles called asphaltene sludge. This can restrict or completely plug the flow channels in the producing formation thereby reducing the effectiveness of the acid treatment and due to its insoluble in most treating solutions, it is extremely difficult to be removed. Hence, in the treatment of wells with asphaltenic crudes which can be identified by simple laboratory tests, sludge prevention procedures should be adopted.

Most limestone and dolomite formations produce through a network of fractures and vary in acid solubility whose acid at varying rates attack the surface of the formation. These formations can exist in an unfractured state. Normally, an interval will accept acid through the fractures more readily and at lower pressure than through the pore spaces. The acid solution reacts with the walls of the flow channels, increasing the width and conductivity of the fractures. Also, when the acid attack formation at varying rates, it leaves an unevenly etched faced. The existence of natural fractures, that occur at random intervals and in random sizes, contribute to the final uneven etching configuration. The type of acid and strength are equally important factors in influencing the etch pattern.

VI. METHODOLOGY

Pressure transient analysis were carried out on well J8 and K35 with a well test analysis tool of a known oil field in Niger Delta region of Nigeria, a continent of Africa. The results obtained showed that these wells were stimulation candidate. Therefore, stimulation operations were performed on these wells and a pre and post evaluation are presented in the result. The well, reservoir and pressure data of Well J8 & K35 are given in Table 1 & 2 of appendix A.

VII. RESULT

From the pressure transient analysis to determine the well J8 skin and permeability using sapphire as show in the appendix. The pressure data (Table 1 in appendix A) indicates a buildup test, which implies that the well must have been flowing for a long time before it was shut-in for the buildup test. Result (Figure 2 in appendix A) obtained when these data were inputted into the well test analysis software; gave a skin value of 3 and capacity of 498 mD-ft. This is an indication of damage as a result of the positive skin. Hence requires a stimulation job to remove the damage. While well K35 (Figure 3 in appendix A) is highly damage with skin of 24.3 and capacity of 48800 mD-ft. This also requires a stimulation operation for the damage removal to increase the well's productivity

7.1 Result of Pre and Post evaluation of Well J8

In other to increase productivity in well J8, it was recommended for stimulation as a result of the positive skin value from pressure transient analysis. This well was stimulated and a reduced value of skin due to damage was obtained as shown in Table 3; but other skin values such as completion, partial and full penetration, slanting of well etc. did not change because they do not require stimulation operation to remove the damage; hence a workover job is recommended. The result justifies a successful well stimulation job with an increase in flow rate of 29stb/d and productivity index increase from 0.9626– 1.9582 stb/d/psi. Also, the inflow performance relationship of the well before and after the well is stimulated is tabulated in table 4 and plotted in Figure 4. Figure 5 represents the plot of production increase with oil production.

Table 3: Result pre-simulation and post stimulation test (well J8)

Parameter	Pre-Stimulation	Post-Stimulation
Rate [stb/d]	350	379
total skin S_T	4.03	2.137
damage skin	3	1.107
other skin	1.03	1.03
ΔP due to damage skin	270.5596145	100.2571974
ΔP due to total skin [psi]	363.4517488	193.5407686
productivity index [stb/d/psi]	0.962988901	1.958243747
increase in production [stb]	29	

Table 4: Inflow performance of well J8 before and after stimulation

Before stimulation		After stimulation			
Press [psi]	**Rate [stb/d]**	**Press[psi]**	**Rate [stb/d]**	**Increase in Production**	**% increase**
4672	0	4672	0	0	0
4476.45	49.54	4476.45	59.97	10.43	21.05369
4107.87	137.82	4107.87	166.83	29.01	21.04919
3739.29	219.42	3739.29	265.61	46.19	21.05095
3370.71	294.35	3370.71	356.31	61.96	21.04977
3002.13	362.61	3002.13	438.93	76.32	21.04741
2633.55	424.19	2633.55	513.48	89.29	21.04953
2264.97	479.1	2264.97	579.95	100.85	21.04989
1896.39	527.34	1896.39	638.35	111.01	21.05093
1527.81	568.91	1527.81	688.66	119.75	21.04902
1159.23	603.8	1159.23	730.9	127.1	21.05002
790.65	632.03	790.65	765.07	133.04	21.04963
422.07	653.57	422.07	791.15	137.58	21.05054
53.49	668.45	53.49	809.16	140.71	21.05019
0	670.06	0	811.1	141.04	21.04886

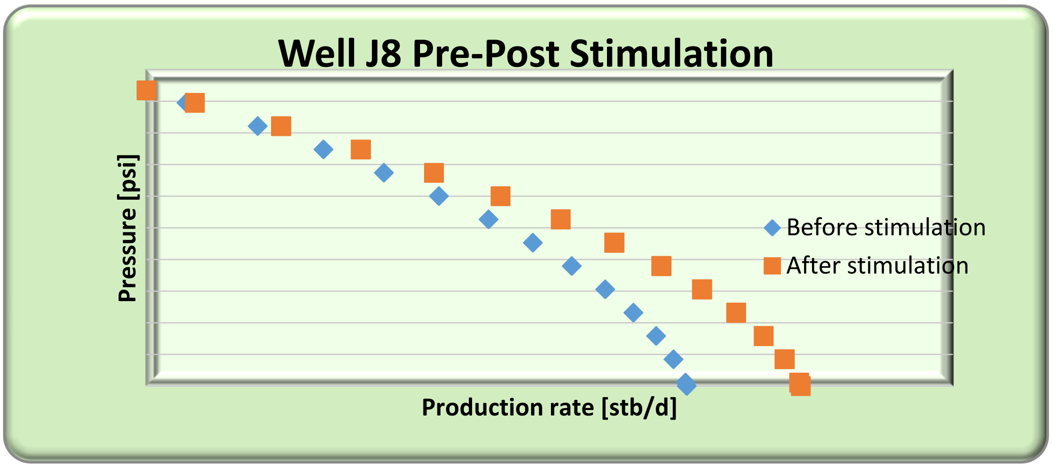
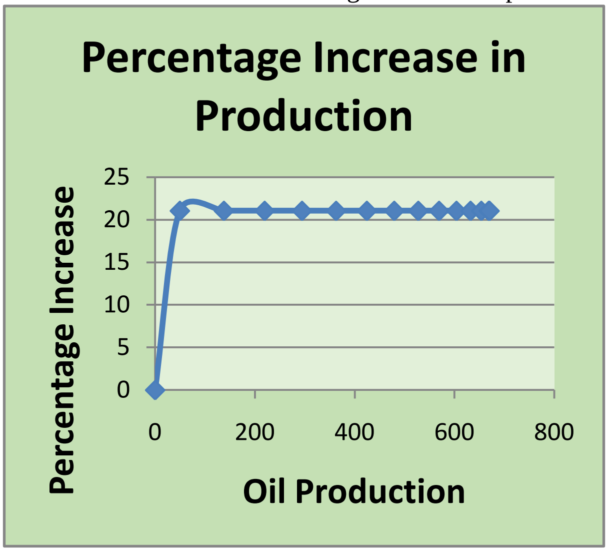


Figure 4: Inflow performance relationship of well J8



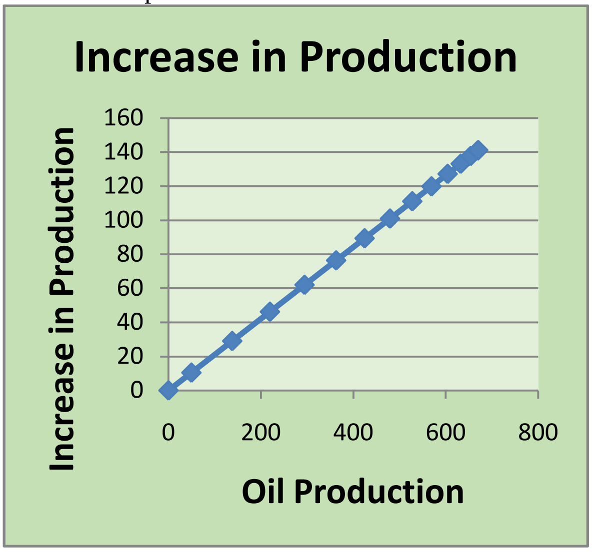


Figure 5: Plot of production increase versus oil production of well J8

7.2 Result of Pre and Post evaluation of Well K35

The result from the pressure transient analysis indicates that the well was damage during the drilling operation and as such a stimulation job was performed which yielded an increase in production rate of 180stb/d and productivity index of 27.0364 stb/d/psi as shown in Table 5. In addition, there was a large reduction in the value of skin due to damage of this well. We will say at this point that the stimulation job is justified as a success. The inflow relationship and percentage increase in production is tabulated in Table 6 and plotted in Figure 6 & 7 respectively.

Table 5: Well k35 result for before and after stimulation

Parameter	Pre-Stimulation	Post-Stimulation
Rate [stb/d]	1000	1180
total skin S_T	31.19	14.14
damage skin	24.3	7.25
other skin	6.89	6.89
ΔP due to damage skin	47.45969262	13.92378842
ΔP due to total skin [psi]	60.9163709	27.15618873
productivity index [stb/d/psi]	16.41594838	43.452342
increase in production [stb]	180	

Table 6: IPR for well k35 before and after stimulation

Before stimulation		After stimulation			
press [psi]	rate[stb/d]	press [psi]	rate[stb/d]	Increase in Production	% increase
3251.23	0	3251.23	0	0	0
3184.42	129.88	3184.42	153.2605	23.3805	18.00162
2985.63	502.18	2985.63	592.5703	90.3903	17.99958
2786.84	853.28	2786.84	1006.867	153.587	17.9996
2588.05	1183.18	2588.05	1396.151	212.971	17.99988
2389.26	1491.88	2389.26	1760.423	268.543	18.00031
2190.47	1779.39	2190.47	2099.681	320.291	18.00004
1991.68	2045.7	1991.68	2413.927	368.227	18.00005
1792.89	2290.81	1792.89	2703.16	412.35	18.00018
1594.1	2514.73	1594.1	2967.38	452.65	17.99994
1395.31	2717.45	1395.31	3206.588	489.138	17.99989
1196.52	2898.97	1196.52	3420.782	521.812	17.99991
997.73	3059.29	997.73	3609.964	550.674	18.00006
798.94	3198.42	798.94	3774.133	575.713	17.99992
600.15	3316.35	600.15	3913.29	596.94	17.99991
401.36	3413.08	401.36	4027.433	614.353	17.99996
202.57	3488.61	202.57	4116.564	627.954	18.00012
3.78	3542.95	3.78	4180.682	637.732	18.00003
0	3543.78	0	4181.658	637.878	17.99993

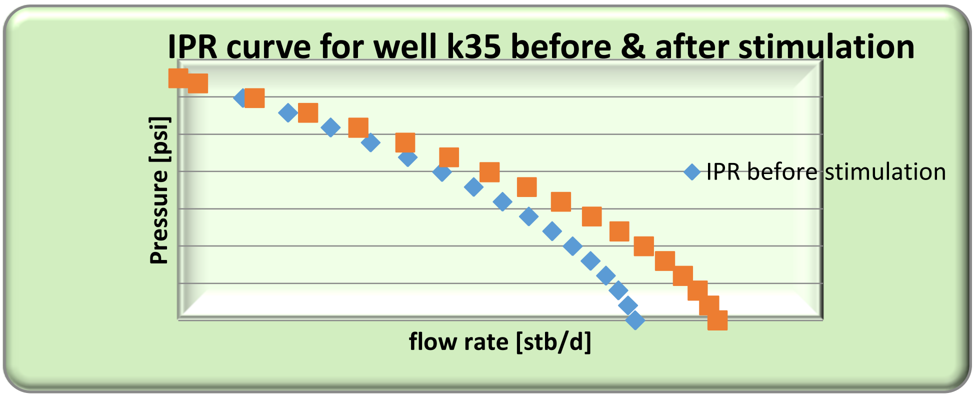
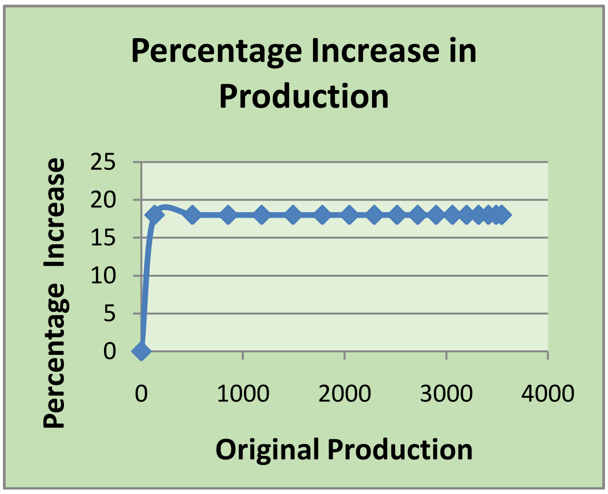


Figure 6: Inflow performance relationship of well k35



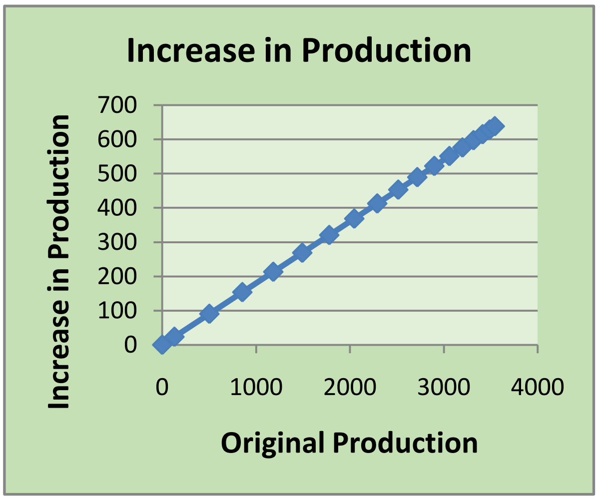


Figure 7: Plot of production increase versus oil production of well K35

VIII. ECONOMIC EVALUATION

8.1 Material Requirement

- 1500 gallons Nitrogen (N_2)
- 7 gallons A260 inhibitor
- 1970 gallons NH_4Cl
- 121 gallons U66 solvent
- 28 gallons F78 surfactant
- 3120 gallons 32% HCl
- 1700 gallons diesel
- 65 gallons U42 Iron control

In Table 7, from the economic evaluation, if we place the two wells under same material requirement, operating condition and cost of operation, it took a break even or payback period of 1.79days approximately 2days for well J8 and a day for well k35 to recover the sum money spent on the total stimulation job. Hence, the payback period is short and this justified the stimulation job on well J8 and k35. Also, based on the data given for this study, the remaining life of these well could not be determine and should be recommended in the next study on this topic to justify stimulation jobs.

Table 7: Economic evaluation

Items	Amount (well J8)	Amount (well k35)
Cost estimated	$ = ₦85.00	$ = ₦85.00
Cost of chemicals	₦705,390	₦705,390
Cost of equipment/personnel's	₦1,897,000	₦1,897,000
Total cost	₦2,602,390	₦2,602,390
Production rate after treatment	379bopd	1180bopd
Cost per barrel of crude oil	@ $45 per barrel = 85 × 45 =3825	@ $45 per barrel = 85 × 45 =3825
Cost of crude produced after treatment	3825 x 379 = 1449675	3825 x 1180 = 4513500
Payback period	Total cost (of chemicals/equipment)/cost per bbl x production rate after treatment =2602390/1449675 = 1.79 days	Total cost (of chemicals/equipment)/cost per bbl x production rate after treatment =2602390/4513500 = 0.58 days

IX. CONCLUSIONS

Based on the analysis of pressure transient and the determination of skin, it is very important to determine the type of skin on each well, this well help in knowing the type of solution to the problem in order to increase the well's productivity because a well whose skin is due to completion, partial penetration or slanting of well does not require stimulation and if the field's operators go ahead to stimulate, they will only end up in wasting time and money without achieving any result because these skin cannot be removed by stimulation. Hence, it is paramount to determine the type and extent of damage.

Also, calculation of the pressure drop should not be accounted for by only skin due to damage because other skin might still be there which are inherent during the well completion stage and as such if operators fail to account for these; value gotten might be wrong and desired rate might not be achieved since the sources of damage are not known to them.

The result of the pressure transient analysis for well J8 and K35 indicated that these wells were damage during the drilling stage probably due to inversion of mud into the formation.

Finally, results obtained after stimulation jobs on these wells (J8 & K35) justify the merit of the well stimulation since there were considerable increases in production rate and productivity index with decrease in the damage skin for both wells analyzed in this study.

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Appendix A

Table 1: pressure data of well J8

Well J8			
Well and Reservoir data		**Del t[hrs}**	**Pws[psia]**
porosity	0.23	0	3561
ct [psi-1]	1.70E-05	0.333	3851
oil viscosity[cp]	0.8	0.5	3960
bo [rb/stb]	1.136	0.667	4045
rw[ft]	0.29	0.883	4104
qo[stb]	350	1	4155
tp[hr]=	4320	2	4271
A [acre]	336400	3	4306
h [ft}	49	4	4324
		5	4340
		6	4352
		7	4363
		8	4371
		9	4380
		10	4387
		20	4432

Table 2: pressure data of well K35

Well K35			
Additional data		**Del t[hrs}**	**Pws[psia]**
porosity	0.25	0	3183.763
ct [psi-1]	2.00E-05	0.0001	3184.281
oil viscosity[cp]	6.00E-01	0.0008	3187.768
bo [rb/stb]	1.125	0.002	3193.224
rw[ft]	0.5	0.0048	3203.799
qo[stb]	1000	0.012	3221.209
tp[hr]=	1000	0.0278	3235.686
A [acre]	80	0.0557	3240.73
h [ft}	50	0.0888	3241.795
vis	0.6	0.1776	3242.698
		0.3774	3243.372
		0.5376	3243.372
		0.7776	3244.368
		1.0176	3244.368
		1.2576	3244.574

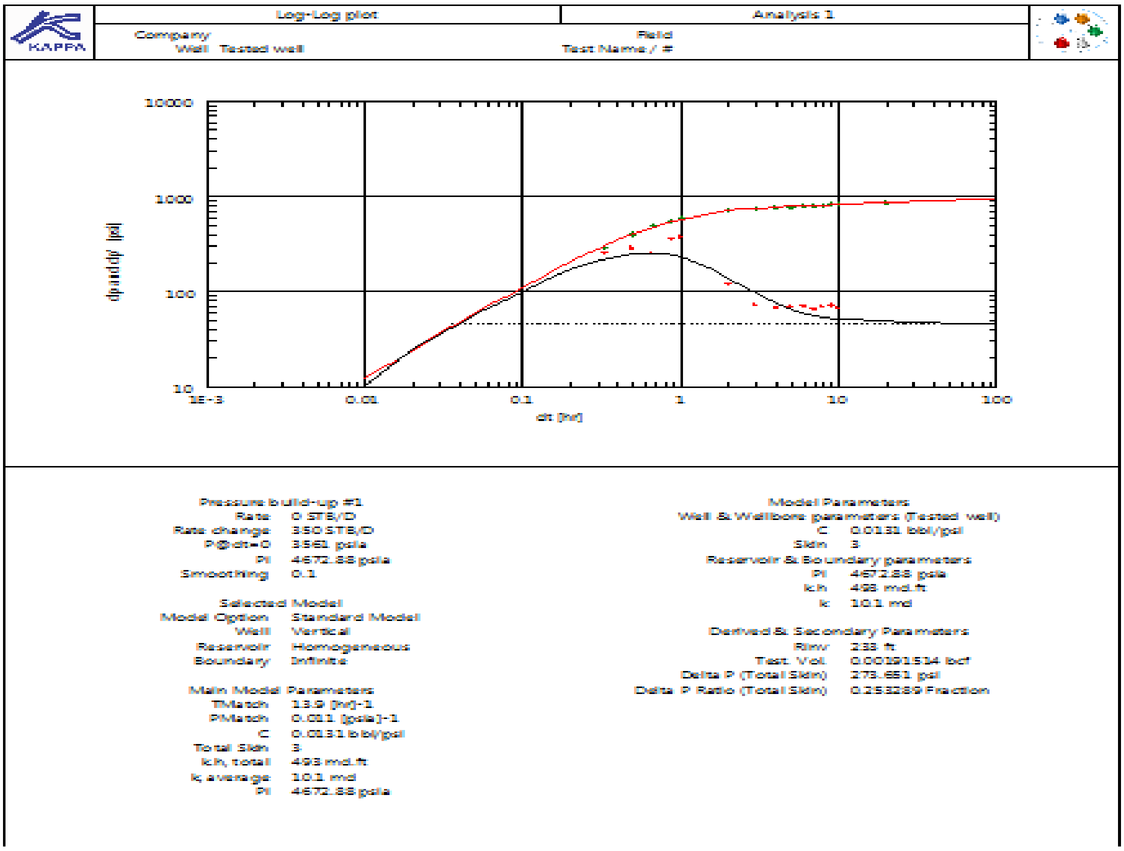

Figure 2: Well J8 log-log well test model plot

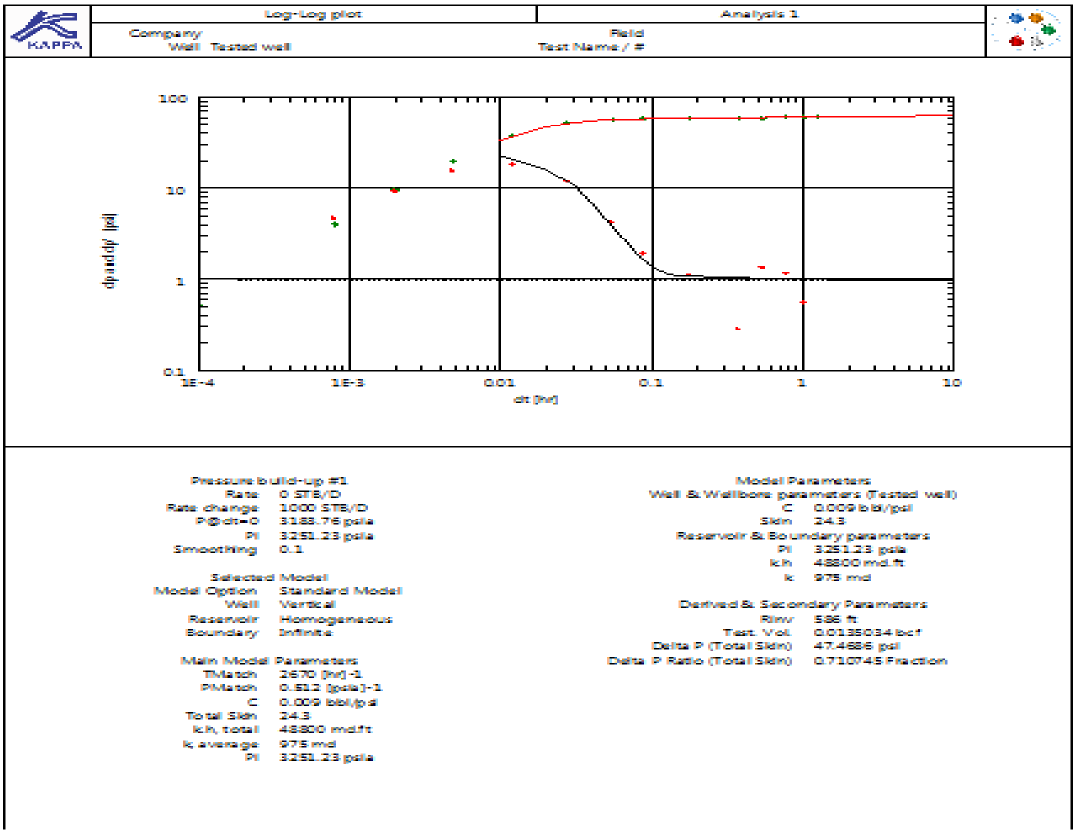

Figure 3: Well K35 log-log well test model plot